### COMMONWEALTH OF MASSACHUSETTS DEPARTMENT OF PUBLIC UTILITIES

Investigation by the Department of Public Utilities
On its Own Motion into Rate Structures that will
Promote Efficient Deployment of Demand Resources

D.P.U. 07-50

### COMMENTS OF THE ATTORNEY GENERAL

Respectfully submitted,

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### I. INTRODUCTION

On June 22, 2007, the Department of Public Utilities ("Department") opened an inquiry to investigate rate structures and revenue recovery mechanisms that may reduce disincentives to the efficient deployment of demand side resources in Massachusetts. Investigation by the Department of Public Utilities on its own Motion into Rate Structures that will Promote Efficient Deployment of Demand Resources, D.P.U. 07-50 (2007). ("June 22 Order"). The Department indicated that this investigation will review features of the current ratemaking practices by which electric and natural gas utilities in the Commonwealth recover their prudently incurred, just and reasonable costs (including return on investment), and will consider whether and how existing mechanisms may be changed to better align companies' financial interests with the needs to (1) capture all available and economic system and end-use efficiencies and their associated reliability, economic and environmental benefits, and (2) foster the advancement of price-responsive demand in regional wholesale energy markets. June 22 Order, p. 1. The Department stated that "the goal of this inquiry is to establish guidelines that will govern the Department's approach to fulfilling its existing statutory obligation under G.L. c. 164, § 94 to investigate the propriety of any rate, price or charge collected within the Commonwealth for the sale and distribution of electricity or natural gas." *Id.* 

Pursuant to the procedural schedule, the Attorney General submits these

Comments on the issues and questions set forth in the Department's June 22 Order.

### **II.EXECUTIVE SUMMARY**

The Office of the Attorney General has long supported the principle that the state's electric and natural gas distribution companies should pursue cost-effective energy efficiency programs. Demand Side Management ("DSM") programs¹ have become increasingly important tools to mitigate and reduce emissions from generation plants and to make the most of our natural gas and electric resources. Strong public policy concerns require a renewed examination of cost-effective DSM programs for all customer classes that are to be provided by the utilities, independent contractors, or both. The Attorney General welcomes the Department's fresh look into any existing disincentives to the efficient deployment of demand resources in Massachusetts.

The Department has stated that it opened this investigation to examine whether electric and gas utilities have an incentive to deliver more energy and whether utilities can, in fact, cause their customers to consume more units of energy. If new energy efficiency, distributed resource and demand response programs are implemented, utilities may seek to deter these new investments because they may not earn their allowed revenue requirement unless rates are reset in a base rate case. The Department has indicated that it will examine existing rate mechanisms and consider whether and how these existing mechanisms may be modified to capture all available system and end-use efficiencies. The Department has also indicated that it will consider the concept of "Revenue Decoupling," a theory which purports to sever the link between revenues and sales to eliminate utility disincentives to new DSM programs.

<sup>&</sup>lt;sup>1</sup> Demand-Side Management ("DSM") "means any technology, measure, or action designed to decrease the kilowatt or kilowatt-hour use, or to alter the time pattern of that use by consumers of electricity." 220 C.M.R. § 11.02.

Before the Department considers moving forward with any changes to the existing regulatory framework, it should make a thorough review in this proceeding of the current state of the energy efficiency programs already in effect, and have a thorough understanding of the resources and purpose of any new programs that the Commonwealth may implement in the future. Massachusetts is a national leader in energy efficiency programs and the implementation of such.<sup>2</sup> The Commonwealth's spending per capita on energy efficiency expenditures is the second highest in the Nation. This has resulted in one of the lowest usage per customer rates in the country. Massachusetts energy efficiency programs have been tested and improved over the years and are considered some of the best in the Nation.

Part of the success of the Massachusetts programs is due to the fact that for the last twenty years, the Department has taken steps to eliminate the market imperfections and barriers that prevent DSM programs from achieving their full potential. As part of this effort, the Department has allowed utilities to recover all direct costs of DSM, lost revenues related to DSM activities and DSM incentive payments. The Electric Industry Restructuring Act of 1997 ("Restructuring Act") created a mandatory per kilowatt-hour charge for electric consumers for energy efficiency activities, removing the risk that a utility's revenues would be insufficient to meet the demands of the efficiency programs. *See* G.L. c. 25, § 19. Similarly, The Department allowed the same ratemaking treatment

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http://aceee.org/store/proddetail.cfm?CFID=26672&CFTOKEN=43169571&ItemID=433&CategoryID=7

<sup>&</sup>lt;sup>2</sup> Eldridge, Prindle, York and Nadel, "The State Energy Efficiency Scorecard for 2006", ("Energy Efficiency Scorecard") Report Number E075, American Council for an Energy Efficient Economy (June, 2007) ranking Massachusetts number four with three states tying for first place. The report scores include categories that are not strictly within the energy efficiency programs administered by the utilities. It is within these categories that Massachusetts could improve its score. These include: building codes, transportation policies, appliance and equipment standards, tax incentives and the state's leading by example. *See* 

for gas companies, dollar-for-dollar recovery for DSM costs through the Local Distribution Adjustment Clause ("LDAC").

In its review of existing energy efficiency programs and company incentives, the Attorney General recommends that as a first step, the Department identify those actions that utilities are undertaking to either increase sales or to deter the expansion of efficiency, demand response or distributed resources. In addition, all other non-utility barriers, including customer barriers, should be identified. That review should also include whether decoupling proposals will discourage customers from energy conservation efforts. Once those market barriers have been identified, targeted least-cost solutions should be adopted by the Department to remove these disincentives, including but not limited to decoupling.

Further elimination of barriers to the deployment of DSM may not require a drastic change to current rate making practices. It could involve changes to rate design, peak pricing initiatives or the manner in which energy efficiency programs are managed and delivered. Such changes can be accomplished under current rate making principles, when a utility, if it believes that it is not earning an appropriate return on its investment, could file a rate case. Moreover, policy and legislative changes outside of the regulatory sphere may have just as significant an impact on energy efficiency as a change to rate making practices. Changes to the building code, increased energy efficiency standards for consumer products, phasing out of inefficient lighting technology and tax incentives for energy efficient products may have the potential to significantly reduce overall energy consumption.

While the Department's straw man proposal raises many concerns for ratepayers, the overall approach to decoupling of using a company's allowed revenues per customer for each rate class without changes between base rate proceedings provides the simplest, least controversial method, after rates have been established. If the Department decides to move forward with a decoupling mechanism, additional changes set forth below must be made to the proposal to protect customers. Decoupling will substantially reduce utility investment risk by stabilizing its variation in the future cash flow streams from distribution sales revenue and its earnings. There would be little uncertainty regarding company earnings. However, there are limits to what customers are required to pay under whatever ratemaking methodology the Department adopts. Customers are only required to pay a return on investment that is equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. If the Department shifts sales risks from shareholders to customers, this reduction in risk must be reflected in the allowed rate of return. If customers are required to pay for all lost revenues,<sup>3</sup> regardless of their root cause, this reduction in risk must be reflected by a downward adjustment to the allowed rate of return.

Furthermore, if the Department decides to move forward with a new decoupling mechanism, it must remove the *eight percent cost adder* presently provided to companies to incent them to administer the energy efficiency programs and compensate them for lost revenues. These financial incentives must be removed because decoupling will make the companies financially neutral to lower sales caused by increased DSM. Therefore,

<sup>&</sup>lt;sup>3</sup> The loss of revenues can be associated with such factors as DSM, bad debt, weather, customer reaction to increased prices, customer self-help remedies, general economic conditions and service outages.

continuing the eight percent cost adder will be redundant, unnecessary, and unreasonable, if the Department introduces another decoupling scheme.

Finally, special attention must be paid to the large commercial and industrial customer classes in any new decoupling scheme. These classes have more diverse use and usage patterns than the residential and small commercial and industrial classes.

These characteristics make the use of gross benchmarks like the average usage per customer revenue decoupling adjustment for these large usage classes much less meaningful and useful. Therefore, the Department should provide special care when applying any decoupling mechanism to the large use classes.

The Attorney General agrees with the Department, that, as a condition precedent to the implementation of decoupling mechanism, a G.L. c. 164, § 94 rate case is required, including the review of cost-of-service studies, cost-allocation, and rate design. A utility claim for additional revenues is best reviewed on a case-by-case basis although general guidelines can be developed in this docket to assist in that process.

Massachusetts should continue to determine and install the optimal amount of DSM by balancing the goals of a clean environment, least-cost and economic development. Massachusetts utility consumers already pay some of the highest electric and natural gas rates in the Country. This includes some of the largest expenditures for DSM Programs. In this proceeding, the Department must ensure that proposed regulatory changes are necessary and adhere to the Department's obligation to ensure those utilities companies subject to its jurisdiction provide safe, reliable and the least expensive rates to consumers. Changes to traditional ratemaking principles should be specifically targeted

<sup>&</sup>lt;sup>4</sup> Massachusetts has the second highest Residential, Commercial and Industrial rates in the continental United States. Energy Information Agency, *Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State* (May 2007). *See* Appendix B.

to enhance cost-effective DSM and ultimately stabilize or reduce prices for Massachusetts ratepayers.

It has yet to be determined whether decoupling is a necessary or critical measure to increased DSM. Nevertheless, if the Department can establish that current rate making principles are a barrier to greater energy efficiency, decoupling, if designed and implemented properly and carefully, may reduce or eliminate this disincentive without increasing costs to consumers; but if the design and implementation fails to strike the right balance, it may yield highly undesirable results for Massachusetts ratepayers.

### III. IDENTIFYING THE DISINCENTIVE

There is much public discussion about a concern that utility actions reflect a disincentive to promote, to the best of their ability, demand side management and energy efficiency programs that clearly benefit customers and society as a whole. In this docket, the Department is investigating whether current ratemaking practices need to be changed, adjusted, or supplemented in order to better align company incentives with important demand resource, price mitigation, environmental, and other policy objectives. In its *June 22 Order*, the Department assumes that disincentives exist and that the disincentives are affecting the utilities in their performance in the doing their best to promote DSM. While the Department may be able to institute decoupling under its existing statutory authority, the Department does not cite any specific evidence proving that a disincentive exists nor has the Department relied on any evidence to make a determination that utility

performance is less than exemplary in the design, development and delivery of energy efficiency programs as the result of the disincentive.<sup>5</sup>

The Attorney General is unaware of any direct actions by utilities to deter DSM development. Should this investigation yield such a finding, the Attorney General recommends that the Department order an immediate reduction in that Company's return on equity. *See Western Massachusetts Electric Company*, D.P.U. 89-260, pp. 87-88 (1990) (A company's willful disregard of its responsibilities in the area of conservation indicates a failure to fulfill its service obligation to provide least-cost service and will be a factor in determining an appropriate return on equity).

As part of this investigation, and as a prerequisite to any ratemaking changes, the Department should make the necessary determination that a disincentive exists and that this disincentive is actually detrimental to the deployment of cost-effective demand side efficiency efforts. The Department has previously adopted such an approach in D.P.U. 86-36-F when it reviewed barriers to further DSM development prior to the implementation of regulatory changes.

As part of this proceeding, the Department should investigate and determine the level of performance each utility's DSM program has achieved. If this investigation reveals that the utilities' performance is exemplary, the Department may seek to enhance

<sup>&</sup>lt;sup>5</sup> The Department has broad discretion to depart from established policy after a specific finding that such changes are within the public interest. *Deacon Transportation, Inc. v. Department of Public Utilities*, 388 Mass. 390, 395-396 (1983); *New England Telephone & Telegraph Company v. Department of Public Utilities*, 372 Mass. 678, 680 (1977). *see also Western Massachusetts Bus Lines, Inc. v. Department of Public Utilities*, 363 Mass. 61, 63-64 (1973); *Alemeida Bus Lines, Inc. v. Department of Public Utilities*, 348 Mass. 331, 344 (1965). "[T]he requirement of "reasoned consistency" in *Boston Gas Company v. Department of Public Utilities*, 367 Mass. 92 (1975), means that any change from an established pattern of conduct must be explained." *Robinson v. Department of Public Utilities*, 416 Mass. 668, 673 (1993). "It does not mean that the DPU may never deviate from its original position." *Id.* However, the Department must set forth a statement of reasons for the decision, including an explanation of why the current system of utility compensation is creating disincentives and what disincentives a new methodology is designed to cure.

and build upon these successful models rather than introduce a rate mechanism to off-set a "disincentive" that may not exist.<sup>6</sup>

### THE DEPARTMENT RATEMAKING POLICIES REGARDING DEMAND SIDE MANAGEMENT HAVE WORKED

### A. Background

Since the early 1980s, the Department has articulated a policy that electric utility "companies should take steps to capture all cost-effective C&LM [Conservation and Load Management] and to ensure that C&LM program opportunities are available to all ratepayers." Investigation into the Pricing and Ratemaking Treatment of New Non-Qualifying Electric Generating Facilities, D.P.U. 86-36-F, p. 24 (1988) (citations omitted); see also Boston Edison Company, D.P.U. 85-266-A/85-271-A, p. 145 (1986) (citations omitted). The Department has required Massachusetts electric utilities to pursue DSM programs only to the extent that such actions are cost-effective from the ratepayers' perspective. Western Massachusetts Electric Company, D.P.U. 86-20-A, p. 252 (1987); see also D.P.U. 86-36-F, p. 7.

Consistent with this policy, the Department has undertaken a number of measures designed to reduce barriers to full implementation of DSM in Massachusetts. More than seven years have passed since the Department conducted a comprehensive review of the regulatory, market, and legal infrastructure affecting deployment of DSM. See generally Order Promulgating Final Guidelines to Evaluate and Approve Energy Efficiency

<sup>&</sup>lt;sup>6</sup> "Absent precise explanation of methodology as applied to the facts of the case, there is no way for a court to tell whether the Commission, however expert, has been arbitrary or unreasonable." Washington Public Interest Organization v. Public Service Commission, 393 A.2d 71, 77 (1987) cert. denied 444 U.S. 926 (1979).

*Programs*, D.T.E. 98-100 (2000). The Attorney General believes that it is now time to take a fresh look at any remaining regulatory barriers to increased customer DSM.

## B. The Department's DSM Ratemaking Policies Prior To Electric Industry Restructuring

Beginning in the 1980s, DSM programs were developed to help address the growing need for generation capacity in Massachusetts and in New England.<sup>7</sup> The Department promulgated rules that increased the role that DSM played in meeting the state's electricity needs.<sup>8</sup> As part of that effort, the Department determined that certain financial barriers thwarted the implementation of DSM in Massachusetts.

Under the then existing regulatory regime, utilities could only recover a representative level of costs for DSM program expenditures through base rates, making expenditures vulnerable to prudence reviews, and bringing various levels of uncertainty to cost recovery for DSM expenditures. Moreover, "the only financial incentive electric companies [had] to reduce sales through exemplary performance of their C&LM programs [was] the Department's power to disallow costs and set a company's rate of return." *See* 86-36-G, p. 117. There was also no opportunity to recover any of the revenues "lost" as a result of the DSM programs, nor the opportunity to earn performance incentives, leaving utilities with little impetus to pursue DSM programs. In some cases, utilities openly resisted the implementation of DSM programs.

<sup>&</sup>lt;sup>7</sup> See generally Power to Spare: A Plan Increasing New England's Competitiveness Through Energy Efficiency, New England Policy Council (1987); see also D.P.U. 86-36-F, p. 7.

<sup>&</sup>lt;sup>8</sup> Investigation into the Pricing and Ratemaking Treatment of New Non-Qualifying Electric Generating Facilities, D.P.U. 86-36-C, p. 1 (1988); see also D.P.U. 86-36-F, pp. 7-9; Investigation into Proposed Rules to Implement Integrated Resource Management Practices for Electric Companies, D.P.U. 89-239, pp. 93-98 (1990) (establishing final rules on integrated resource management).

<sup>&</sup>lt;sup>9</sup> See Boston Edison Company, D.P.U. 85-266-A/85-271-A, p. 147 (1986)(stating that the Department "[c]onclude[d] that the Company ha[d] intentionally and willfully mischaracterized [the Department's]

The Department determined that utilities needed to play a larger role in the identification and development of DSM and made a number of ratemaking changes. <sup>10</sup>

See generally D.P.U. 86-36-F; see also Integrated Resource Management, D.P.U. 89-239, pp. 94-98; Western Massachusetts Electric Company, D.P.U. 89-260, p. 121 (1990); Massachusetts Electric Company, D.P.U. 89-194/195, p. 178 (1990). The Department altered its policies and allowed companies to recover all the direct DSM costs. D.P.U. 89-239, pp. 97-98. It also held that "utilities could obtain pre-approval ratemaking treatment of major electric company investments in C&LM . . . ," removing the risk of a prudence review. See D.P.U. 86-36-F, p. 29. Finally, the Department held that utilities could earn a return on C&LM investments that it owned, and that they could amortize those assets they did not own. D.P.U. 86-36-F, p. 33. These measures ensured that utilities could recover DSM related expenditures and helped eliminate utility resistance to DSM.

The Department also addressed the potential that utility revenues may be lost or eroded as a result of reduced sales attributable to DSM programs. To correct this problem, the Department allowed recovery of lost base revenues. D.P.U. 86-36-F, p. 20-21. The Department held that to the extent that these lost revenues become significant and can be quantified, "rates (although not total average bills) would have to be increased to make the [utility] company whole." D.P.U. 86-36-F, p. 21. It allowed the recovery of "Lost Base Revenues" in order to "restore the assumed relationship between sales levels

Orders [clearly directing the Company to implement C&LM] so as to relieve it of the obligation to proceed with cost effective C&LM programs"); *see also Id.* pp. 144-149.

<sup>&</sup>lt;sup>10</sup> The Department found that utilities "direct involvement . . . in marketing and implementing C&LM options is necessary and appropriate." D.P.U. 86-36-F, p. 18.

and revenue requirements that were used in setting the rates." <sup>11</sup> *Boston Edison Company*, D.P.U. 95-1-CC, p. 73 (1995) *citing* D.P.U. 89-260, p. 105. The Department implemented this policy on a case-by-case basis "where the level of demand or energy sales reduction is significant in comparison with the company's total load or sales volume." D.P.U. 86-36-F, p. 35. <sup>12</sup>

Finally, the Department had concluded that incentives were necessary to ensure that utilities aggressively pursued DSM programs. Favorable DSM ratemaking treatment would not, on its own, motivate utilities to aggressively pursue DSM. *See* D.P.U., 89-239, pp. 93-94; *see* also D.P.U. 89-260, p. 121. Therefore, the Department instituted a policy that utilities could earn financial performance based incentives for successful implementation of DSM. *Id.*, p. 98; *Massachusetts Electric Company*, D.P.U. 89-194/195, p. 178. The Department "[f]ound that it would be appropriate to implement a system that rewards electric companies that are successful in implementing . . . utility [conservation and load management] projects." *Id.*, p. 94.

The Department has adopted four ratemaking policies/mechanisms to encourage utilities to pursue DSM: (1) pre-approval of DSM program expenditures; (2) inclusion of expenditures in rate base; (3) compensation for revenue erosion, and (4) performance based incentives.

<sup>&</sup>lt;sup>11</sup> "Lost base revenues are those revenues that a company does not collect from its ratepayers because of the decrease in the billing unity that result from Demand-Side Management program savings." *Cambridge Electric Light Company/Commonwealth Electric Company*, D.P.U. 95-2/3-CC, p. 1, n. 2 (1995).

<sup>&</sup>lt;sup>12</sup> Lost base revenues are also captured every time a utility has a base rate case. The billing determinants used to set new rates reflect the changes in customer usage.

## C. The Department's DSM Ratemaking Policies Post Electric Industry Restructuring

The Restructuring Act further reduced barriers to implementation of DSM by establishing a System Benefit Charge ("SBC") whereby all customers of electric distribution companies pay a mandatory per kilowatt-hour charge as part of their monthly bill to support "energy efficiency activities." <sup>13</sup> G.L. c. 25, § 19. Electric utilities receive SBC funds to administer energy efficiency programs within the Commonwealth, the Division of Energy Resources ("DOER") oversees and coordinates the utility programs, and the Department reviews the programs to ensure "[t]hat they are delivered in a costeffective manner utilizing competitive procurement processes to the fullest extent practicable." See G.L. c. 25, § 19; G.L. c. 25A, §11G. SBC funding for energy efficiency has reduced shareholder risk associated with cost recovery of DSM, by providing a steady stream of funding for energy efficiency. See Energy Efficiency Cost-Effectiveness, D.T.E. 98-100, p. 38-39 (1999) ("As a result of the [Restructuring] Act and the establishment of a general fund for electric energy efficiency initiatives, it is clear that electric companies are not at risk for recovery of the costs of implementing energy efficiency programs.").

The Department also established a financial incentive of eight percent of total program costs. <sup>14</sup> D.T.E. 98-100, pp. 37-40 (Nov. 1999). The Department found that the establishment of incentives "should be sufficient motivation for the utility to strive for high performance in implementing energy efficiency initiatives for both electric and gas

<sup>&</sup>lt;sup>13</sup> The Department allowed similar ratemaking treatment for gas companies, dollar-for-dollar recovery for DSM costs, through the LDAC.

<sup>&</sup>lt;sup>14</sup> Tax affected, the five percent incentive paid to electric utilities equals approximately eight percent of the total amount of the energy efficiency budgets. Natural gas companies may also earn performance based incentives for implementation of DSM. *See Boston Gas Company d/b/a KeySpan Energy Delivery New England*, D.T.E. 03-40, pp. 14-15 (2003).

utilities." D.T.E. 98-100, p. 39. Under the current regulatory regime, in 2006 utilities earned over \$9 million of shareholder incentives.

## D. The Results of Two Decades of DSM Ratemaking in Massachusetts

Based on the above, the Attorney General finds little reason to conclude that the current structure of Massachusetts ratepayer funded DSM programs is ineffective or that the ratepayer funded programs themselves are anything but first rate. To the contrary, both in- and out-of-state analyses indicate that Massachusetts DSM programs have produced significant benefits for the state's ratepayers. The state's already significant funding commitment of approximately \$150 million annually for energy efficiency programs has helped it to become a leader in providing energy efficiency.

A comparative analysis of state energy efficiency policies finds Massachusetts is a top spender on utility energy efficiency programs. *Energy Efficiency Scorecard*, pp. 8-9. Massachusetts ranks number two in the Nation for the highest levels of electric utility spending on a per capita basis. <sup>15</sup> *Id.* Massachusetts, with \$20.81 per capita spending, is only exceeded by Vermont which ranks number one at \$22.54 per capita spending. *Id.* 

Funding alone will not produce good programs. DOER maintains that the DSM programs brought significant benefits to Massachusetts ratepayers and residents for the period 2003-2005. In a report released on April 2, 2007, DOER stated that "for an investment of \$371 million in [electric] ratepayer funds over the three year period, the cumulative lifetime bill savings to all participating customers will amount to

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<sup>&</sup>lt;sup>15</sup> A majority of the states spend little, if any, money on energy efficiency. For example, Colorado ranks 23 with spending \$2.98 and Wyoming, Kansas and Virginia share in the 48 ranking with zero spending. *See* Energy Efficiency Scorecard, pp. 8-9.

approximately *\$1.2 billion*."<sup>16</sup> DOER also reported significant reduction of 216 MW in summer peak demand producing a savings of \$19.5 million in wholesale electric purchases and significant reductions in environmental emissions for the three year reporting period of 2003-2005.<sup>17</sup> *Id*.

To fully maximize energy efficiency efforts and promote DSM, Massachusetts should improve in a number of areas in which the Department has no jurisdiction and legislative action is required. The 2006 Energy Efficiency Scorecard reviewed "state progress in eight energy efficiency policy categories" and it found that Massachusetts ranked lower than other states with regard to building codes, appliance standards, energy efficiency resource standards, tax incentives and state lead-by-example. The policy areas where Massachusetts earned relatively low ratings have little to do with utility implemented DSM programs or ratemaking policies. To build on the success of the Massachusetts energy efficiency efforts, the Commonwealth will need a comprehensive energy efficiency plan that includes policy changes beyond decoupling that fall outside of the Department's purview.

## V. CONCERNS WITH THE DEPARTMENT'S STRAW PROPOSAL AND RECOMMENDED CHANGES

### A. The Straw Proposal Recovers Revenues for Changes in Market Forces Unrelated To Utility Energy Efficiency Efforts

The straw proposal compensates utilities regardless of whether the reduction in revenues is primarily associated with efficiency programs. The straw proposal as written goes far beyond that needed to protect utilities from any reduction in consumption due to

<sup>17</sup> DOER has also previously reported significant savings for the period 1999-2002.

<sup>&</sup>lt;sup>16</sup> Massachusetts Saving Electricity: A summary of the Performance of Electric Efficiency Programs Funded by Ratepayers Between 2003 and 2005, p. 1 (April 2, 2007). http://www.mass.gov/doer

customer DSM actions, including those completely unrelated to utility DSM programs such as customer reaction to the increased price of gas or electricity, general economic conditions, customer self-help remedies such as turning down the thermostat or installing more efficient lighting and appliances. <sup>18</sup>

It is one thing to develop ratemaking mechanisms to compensate utilities for disincentives to statutorily required DSM expenditures, but it is quite another to give gas and electric utilities an automatic adjustment mechanism to compensate them for lost revenues regardless of the cause. A focus on use per customer ignores the overall economic picture and has negative consequences for customers. Any Department policy promoting demand response should, at best, focus on making the utility revenue neutral for mandated efficiency programs and it should not create an automatic increase for any change in revenues for which a utility can quantify.

A decoupling mechanism that is designed to be a financial windfall to utilities raises serious legal questions. Historically, the Department has only attempted to compensate utilities for lost revenues associated with Department or legislatively mandated utility DSM programs. The burden is on the utility to show why it is entitled to compensation for lost revenues unrelated to energy efficiency programs.

Under no circumstances are ratepayers required to indemnify electric and gas distribution companies for lost profits and financial harm caused by the increased use of demand resources or other factors that reduce usage.<sup>19</sup> Investors in a utility are aware

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<sup>&</sup>lt;sup>18</sup> "[T]he Company's ability to earn an allowed rate of return is . . . affected as well by a multitude of . . . factors which are not necessarily within the control of the Company or the Department." *Eastern Edison Company*, D.P.U. 243, p. 9-10 (1980).

<sup>&</sup>lt;sup>19</sup> Utilities have an obligation to serve its customers regardless of loss of load or demand. "This requirement reflects the essential nature of electricity in meeting the states public health and safety and economic requirements." D.P.U. 86-36-C, p. 6.

that not every cost incurred by the utility will be passed along to ratepayers. The fact is that things do not always turn out like management or investors intended given an inherently uncertain future and the vagaries of business cycles. This is a business hazard or risk to which all capital is exposed. Regulation does not insure that the business shall produce net revenues. Federal Power Commission v. Natural Gas Pipeline Company, 315 U.S. 575 (1942). The hazard that property will not earn a profit remains on the company in case of a regulated as well as an unregulated business. Id. A utility has no right to rehabilitation of financial integrity that market forces have undermined. Market Street Railway Company v. Railroad Commission, 324 US 548 (1945); Boston Edison Company v. Department of Public Utilities, 375 Mass. at 17.

Moreover, the Supreme Judicial Court has, relying in part on *Market Street Railway*, *supra*, held that the due process clause cannot be used to support an argument that an electric or gas utility is entitled to rates that "insure values or . . . restore values that have been lost by operation of economic forces." *Fitchburg Gas & Electric Light Company v. Department of Public Utilities*, 375 Mass. 571, 575 (1978) *quoting Market Street Railway Company*, *supra*, 324 U.S. 567; *see also Fitchburg Gas & Electric Light Company v. Department of Public Utilities*, 371 Mass. 881, 883, n. 3 (1977) (observing that the Department is free to determine whether to allow no recovery of uneconomic assets). Under Massachusetts law, as the Department has observed, that "ratepayers are not the guarantors of a company's success." *Western Massachusetts Electric Company*, D.P.U. 85-270, p. 26 (1986) *citing Commonwealth Electric Company v. Department of Public Utilities*, 397 Mass. 361, 363 (1986); *cf. Donham v. Public Service Commission*, 232 Mass. 309, 315 (1919) *quoting Missouri, K. & T. R. Company v. Interstate* 

Commerce Commission, 164 Fed. 645, 648 (1908)(stating "where the cost to the carrier is not kept within reasonable limits, or where for any reason its business cannot reasonably be so conducted as to render it profitable the misfortune must fall upon the carrier, as would be the case if it were engaged in any other line of business . . . ").

No basis exists to support a claim that utilities have a right to insurance against the risk that the forces of supply and demand will work to their disadvantage. Nothing in Massachusetts law compels a different result. The Department cannot, on a prospective basis, conclude that the deployment of new DSM programs or expenditures will result in financial losses for utilities which are chargeable to customers without detailed class-specific evidence.

## B. A Utility's Return on Equity Must Be Dramatically Reduced if the Department Adopts the Straw Proposal

In its *June 22 Order*, the Department has recognized that a base revenue adjustment mechanism "could materially alter the distribution risks among the company, its shareholders, and its customers." *June 22 Order*, p. 17. While the Department concludes that any actual determination of risk must be conducted in the "context of the determination of a company's initial revenue requirement," the Department "will consider in the current inquiry whether it is appropriate to establish common principles or guidelines on how any new base revenue adjustment mechanism could affect the distribution of risks." *Id*.

## 1. AS A MATTER OF LAW, A UTILITY'S RATE OF RETURN MUST REFLECT THE RISKS IT UNDERTAKES IN THE RATEMAKING SYSTEM ADOPTED BY THE DEPARTMENT

"[W]hether a particular rate is 'unjust' or 'unreasonable' will depend to some extent on what is a fair rate of return given the risks under a particular rate-setting system, and on the amount of capital upon which the investors are entitled to earn that return." Duquesne Light Company v. Barasch, 109 S.Ct. 609, 617 (1989). "The risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks." *Id.* at 619.

Shareholders are fully compensated for business risk through the setting of a reasonable rate of return on investment. *Boston Gas Company v. Department of Public Utilities*, 368 Mass 780, 789 (1975). If additional charges are allowed, "[t]he effect upon the consumer would be the same as if an injured person were required to assume the loss against which he believed himself protected by the payment of premiums." *Washington Gas Light Company v. Baker*, 188 F.2d 11, 20 (1950), *cert. denied* 340 U.S. 952 (1951). "The result would clearly violate the consumer interest against 'exorbitant' rates." *Id.* "Ratepayers cannot be required both to carry this risk and pay the Company for carrying it." *Id.* 

<sup>&</sup>lt;sup>20</sup> "[A] State's decision to arbitrarily switch back and forth between methodologies in a way which required [ratepayers] to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions." *Duquesne Light Company*, 109 S.Ct. at 619.

#### 2. SETTING A REASONABLE RATE OF RETURN

The objectives of setting a reasonable rate of return on a utility's rate base include compensating the company's investors for the risks they assume when they lend to the company and buy its stock. The Department states that the purpose of the straw proposal is to ensure that "a company would not be financially harmed by or benefit from changes in sales." *June 22 Order*, p. 12. However, the proposed reconciliation of revenue is not limited to financial harm caused by sales reductions related to DSM programs, but reduction in customer sales for whatever reason.

Plenary indemnification of the utility for any reduction in revenues is nothing less than a shifting of business risk from the investors to the ratepayers. Providing such an upward spiral of rates would indeed represent a patent failure to weigh the interests of the customers in the balancing process of setting rates. Such a view runs counter to the settled law that a regulated utility has no abstract constitutional right to make a profit. *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944).

Regulators must restrike old balances between the competing interests when ratemaking methodologies change. Although the difficulty lies in recognizing where legitimate adjustment ends and impermissible risk-shifting begins, there is at least one general rule that effectively answers the question. That standard has found effective articulation in *Bluefield Company v. Public Service Commission*, 262 U.S. 679, 692 (1923), which holds that risks undertaken by a regulated utility should be compensated by returns commensurate with similar risks in other businesses. The *Bluefield* and *Hope Natural Gas* cases provide the parameters for the determination of the cost of common

equity for a utility. In the *Bluefield* decision, the Court found that a fair rate of return for a regulated utility should be:

- equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties;
- reasonably sufficient to assure confidence in the financial soundness of the utility;
- adequate, under efficient and economical management, to maintain and support its credit and allow it to raise the money necessary for the proper discharge of its public duties.

Bluefield Company v. Public Service Commission, 262 U.S. at 679.

The actual value of the risk transfer will depend on the implementation details of base revenue adjustment mechanism—will all revenue level changes be included in the adjustment (weather, general economic conditions, customer self-help)? <sup>21</sup> If a utility receives an adjustment mechanism that increases the probability that it will actually earn its allowed rate of return, a downward adjustment in its return on equity is required as a matter of law. The more risk that is shifted to customers, the greater the downward adjustment to the ROE should be. The corollary to this is that the more risk shifted to customers the more contentious, complicated and administratively burdensome the related regulatory proceedings will be.

In approving decoupling mechanisms in the context of a rate case, other states have recognized a reduction of risk associated with the plan. In Maryland, decoupling was recently approved for the Potomac Electric Power Company ("PEPCO") and Delmarva Power and Light Company ("Delmarva"). In the PEPCO Order, the

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customers.)

<sup>&</sup>lt;sup>21</sup> See Bay State Gas Company, D.P.U. 92-111, pp. 60–61 (1992); Berkshire Gas Company, D.P.U. 92-210, pp. 199-200 (1993) (Reduction in risk caused by the adoption of a Weatherization Stabilization Mechanism, requires a downward adjustment in the proposed return on capital which must be shared with

Commission recognized the reduced cost of capital, given that the new rate structure will result in improved cost recovery. *In the Matter of the Application of Potomac Electric Power Company*, Order No. 8157, Case No. 9092, p. 72 Public Service Commission of Maryland, July 19, 2007. Similarly, the Commission reduced Delmarva's cost of capital in recognition of the assurance the company has that it will achieve its level of revenue. *In the Matter of the Application of Delmarva Power and Light Company*, Order No. 8158, Case No. 9093, p. 42 Public Service Commission of Maryland, July 19, 2007; *see also Id.*, p. 43 ("In response to this decline in risk, all parties recognize the appropriateness of reducing Delmarva's return on equity by some amount.").

### C. Elimination of Other Cost Recovery Mechanisms

The Department's rate design efforts focus on base distribution rates which recover mostly fixed costs related to distribution plant, metering equipment and customer services—costs that generally do not vary with usage. The recent trend has been to move costs that are perceived to be volatile such as pension related costs and energy related bad debt costs to reconciling automatic adjustment clauses that allow utilities to recover costs dollar-for-dollar. These pass-through clauses are generally designed to collect costs uniformly on an equal cents per kWh or therm basis. By transferring cost recovery from base distribution rates to reconciling mechanisms, the effectiveness of rate design initiatives is reduced—the level of costs passing through base rates has decreased and the ability to send appropriate price signals has been diminished. To strengthen rate design signals necessary to achieve Department policy goals, the Attorney General recommends that the Department eliminate cost recovery mechanisms that would become obsolete: pension expense and post-retirement other than pension ("PBOP") reconciling

mechanisms, price cap adjustments, including exogenous cost adjustments, Residential Assistance Adjustment Factors, and capital addition reconciling mechanisms.

In addition, the Department should also remove the various "attrition" adjustments contained in the calculation of the revenue requirement, such as the use of year-end rate base<sup>22</sup> and inflation allowances,<sup>23</sup> as unnecessary relics under a decoupling mechanism. Both of these attrition adjustments were designed to insure earnings stability and help the Company earn its authorized return. Through the proposed periodic reconciliation of revenues contained in the straw proposal, "revenues would be more closely aligned with costs over time." June 22 Order, p. 12. The annual reconciliation calculation would calculate the difference between actual and allowed revenues and the Company would recover (or credit) the difference over the subsequent twelve-month period. *Id.* These attrition adjustments are required only if the rate to which the utility has been "found to be presently entitled, clearly cannot be earned during the foreseeable effective period of the ordered rates." New England Telephone and Telegraph Company, 331 Mass. 604, 622 (1954). Since the utility will actually earn its forecasted rates during the period in which the rates are effective under the straw proposal, the continued application of attrition adjustments, in effect, double charges customers.

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<sup>&</sup>lt;sup>22</sup> "Year-end rate base is one of several alternatives that are available to mitigate the effects of attrition and regulatory lag in an inflationary economy." *Id.*, p. 4 (1980). *Policy Statement of the Commission Concerning the Adoption of Year-End Rate Base*, D.P.U. 160, p. 3, n. 3 (1980).

<sup>&</sup>lt;sup>23</sup> "This Department is neither unaware of nor unsympathetic to the problems resulting from the twin demons of attrition and regulatory lag. In an attempt to mitigate their damaging effects, we have recently adopted the use of year-end rate base and have granted inflation allowances." *Western Massachusetts Electric Company*, D.P.U. 558, p. 9 (1981).

### **D.** Elimination of Energy Efficiency Incentives

The Department proposes, in this proceeding, to change the manner the companies are financially incented to administer energy efficiency programs. If the Department orders a change to the way the companies incented by introducing a base rate revenue adjustment mechanism that aims to make companies financially neutral to energy efficiency programs, the Department should also eliminate the financial incentives put in place since D.T.E. 98-100. The existing energy efficiency incentives and the revenue adjustment decoupling mechanisms seek to achieve similar goals in ensuring utility administer energy efficiency programs. As the incentives were designed and approved by the Department under ratemaking where shareholders were at risk for sales losses associated with increased DSM, the incentives should be re-evaluated within the context of any ratemaking change in this case and eliminated as they will redundant with the purpose of the new mechanism, unnecessary, and unreasonable.

### VI. Potential Bill Impacts on Customers

### A. In General

In this proceeding, the Department has presented a straw proposal for a base revenue adjustment mechanism "which renders electric and gas companies' revenue levels immune to changes in sales between rate proceedings." *June 22 Order*, p. 10. The proposal is designed to "ensure that electric and gas distribution companies are not financially harmed by the increased use of demand resources." *Id.*, p. 11.

The straw proposal impacts customers in quite a different manner. Quite simply, if existing residential customers reduce their natural gas or electric consumption by half by deploying demand resources that are located on the customers' side of the meters,

under the straw decoupling proposal, these customers as a class would still pay the same amount to the utility for distribution service that they paid when the utility delivered twice as much natural gas or electricity, all other things being equal. The customer would always pay for the actual amount of the gas or electric commodity used at the market price, but their individual conservation efforts would result in an increase in rates paid by all customers for the delivery of the commodity.

The straw proposal addresses only the distribution portion of the customers' rates which represents 40 percent or less of the residential customers' total bill for the delivery of the commodity. Customers that are able to take advantage of demand side programs will see a reduction in their energy charges that may produce a net savings to them. However, a significant number of customers will simply see their bills go up as the result of the Department's revenue adjustment proposal in this case. For instance, any customers who do not avail themselves of energy initiatives will see their bills increase. Similarly, low income customers who do not or cannot avail themselves of any energy efficiency initiatives will see their bills increase. Finally, customers who have already installed all the energy efficiency appliances they can economically purchase will also see their bills increase. The impact on all customers' bills, including those who cannot take advantage of any new energy efficiency programs, should be considered before implementing any new revenue adjustment mechanism.

### **B.** Large Commercial and Industrial Customers

The Department must give special attention to the impact of a decoupling mechanism on large commercial and industrial customers. Massachusetts commercial and industrial customers pay some of the highest rates in the country. *See* Appendix B.

The number of customers in the large commercial and industrial rate class is declining in most electric company service territories. The prospect of increasing electricity rates may accelerate an ongoing exodus of large commercial and industrial users.

## 1. The Department's Decoupling Proposal Cannot Be Applied Uniformly Across All Rate Classes

The Department straw proposal provides for decoupling revenues by adjusting class revenues based on an average usage per customer benchmark. The residential and small commercial classes have less diverse usage patterns within each class than are exhibited by the high usage large commercial and industrial customer classes. The residential and small commercial and industrial classes provide for a more reliable application of usage per customer formula revenue adjustment. The large commercial and industrial classes, however, have more diverse usage and usage patterns. Changes in energy price and economic factors have a much larger impact on their usage. The average usage per customer benchmarks for these large usage classes is much less meaningful. This is especially true when attempting to measure the effects of new energy efficiency programs on the large customer classes.

## 2. The Department Must Prevent the Negative Effects of Decoupling on the Large Commercial and Industrial Classes

A decoupling formula that provides blanket protection for shareholders from all losses of sales for large commercial and industrial customers will have indeterminate effects on energy efficiency gains for those classes and many possible negative effects for the utilities' other customers and for the Massachusetts economy as a whole. Blanket protection may remove incentives for utilities to encourage business to stay and grow

here in Massachusetts. Blanket protection will remove incentives for utilities to maximize sales revenues from customers as they will be incented to add/retain customers at reduced rates by signing special contracts at discounted rates that may ultimately be subsidized by other customers.

Large customer migration from class to class can also have negative effects on the other customers in the classes at both ends of the migration. Large commercial and industrial customers who move from class to class to take advantage of rates and revenue adjustments in the new class can change the average use or average revenue per customer benchmarks dramatically for those classes, causing cross-subsidization and rate increases for certain commercial and industrial customers simply as a result of the migration.

Finally, The Department should not create a situation where large multi-national corporations may be subsidized by smaller commercial and residential customers, who are already paying the highest rates in the country. Any decoupling mechanism should not remove the utilities' incentive to support the economy, through the addition of customers and expansion of existing facilities. Therefore, if the Department adopts any revenue decoupling mechanism for large commercial and industrial customers, it should reject the use of an average usage per customer benchmark and instead make the mechanism very specific to these classes and tie it directly to the energy efficiency programs provided to each of these classes.

<sup>&</sup>lt;sup>24</sup> Compare Standard of Review for Electric Contracts Filed Pursuant to G.L. c. 164, § 94, D.P.U/D.T.E. 96-39-A, p. 2 (1998) (stating "a discount to one customer is not recoverable from remaining ratepayers;"); *Massachusetts Electric Company*, D.P.U. 95-40, pp. 142-143 (1995).

### 3. Customers Face Other Significant Utility Bill Increases

The Department must take into account the impacts of other potential cost changes that will be included in customers' bills. These include increased distribution infrastructure, 25 transmission costs related to the significant expansion and upgrading of the regional transmission system, <sup>26</sup> costs related to the wholesale energy market including forward capacity costs, increases to ancillary costs, potential increased cost of compliance with Renewable Portfolio Standard ("RPS") requirements, and the Regional Greenhouse Gas Initiative ("RGGI"). These costs that will ultimately be borne by retail customers, as will costs related to changes in the general economy (inflation, taxes and capital costs). The Department is urged not to disregard these other bill impacts and create a ratemaking system that is characterized by a never ending spiral of increasing customer bills.

### VII. A BASE RATE CASE IS A PREREQUISITE TO THE IMPLEMENTATION OF A BASE REVENUE ADJUSTMENT MECHANISM

The Department has recognized "the need for completion of a base rate proceeding as a prerequisite for establishing a base revenue adjustment mechanism." June 22 Order, p. 14. The Department "must understand the company's underlying distribution revenue requirement and the allocation of this revenue requirement among classes through an allocated cost of service study." Id. The Department has indicated that it will set rates,

http://www.edisonfoundation.net/Rising\_Utility\_Construction\_Costs.pdf

26 See ISO New England, Inc., Regional System Transmission Project, April 2007-July 2007 Update,

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<sup>&</sup>lt;sup>25</sup> See The Brattle Group, Rising Utility Construction Costs (2007)

http://www.iso-ne.com/trans/rsp/2007/jul07 update final redacted 073107.pdf

using well-established ratemaking precedent including cost of service, cost allocation and rate design. Allowed revenues will be collected through base customer, energy and demand rates, established by customer class.

June 22 Order, p. 4.

The Attorney General agrees with this approach as a necessary prerequisite. Just as with PBR rate mechanisms, the Department must determine appropriate "cast off rates" that are just, reasonable, cost based and are designed to balance the Department's many policy goals.<sup>27</sup> A base rate case is not only essential to the determination of a just and reasonable overall revenue requirement, but also to the establishment of the base to which future adjustments are to be applied for each rate class.<sup>28</sup> A full rate proceeding will allow the Department to conduct a complete examination of costs, investments, revenues and usage patterns necessary to determination of just and reasonable rates and to assure that the Department's ratemaking goals are achieved.<sup>29</sup>

An initial base rate case prior to implementing a revenue adjustment mechanism serves multiple purposes. First, the Department examines costs and investments and determines if the revenue requirement represents the appropriate representative level of costs to be recovered through rates for an indefinite future period. As part of this process the Department determines the cost of equity capital that the utility will be allowed to incorporate in rates based on the risk profile of the utility.

<sup>&</sup>lt;sup>27</sup> The Department must determine the appropriate "cast-off" rates before establishing performance-based rates for distribution rates. *Boston Gas Company*, D.P.U. 96-50, at 346-347 (1996). When performance-based rates are set, a thorough review of the COSS may be necessary to establish the appropriate "cast-off" rates. *Cambridge Electric Light Company*, *Commonwealth Electric Company*, and Canal Electric Company, D.P.U./D.T.E. 97-111, p. 40 n.17 (1998).

<sup>&</sup>lt;sup>28</sup> To meet the Department goal of fairness, "the Department must look to the test period costs to determine the total amount to be allocated and the development of allocators." *Massachusetts Electric Company*, D.P.U. 85-146, p. 10 (1986).

<sup>&</sup>lt;sup>29</sup> The Department has several goals for utility rate structures: efficiency, simplicity, continuity, fairness and earnings stability. *Massachusetts Electric Company*, D.P.U. 85-146, p. 6.

Second, the Department precedent is to set rates based on cost causation principles—a utility's just and reasonable costs are allocated to the various customer classes based upon factors that best represent the level of costs that each class causes the utility to incur. The Department determines the propriety of the allocation of costs among rate classes. The allocation of costs to various customer groups is important to the effective promotion of demand based solutions to reducing energy consumption, reducing peak needs, and the efficient deployment of customer resources. The allocation process also meets the Department's goal of fairness.

Part of the cost allocation process includes the development of an accurate marginal cost study, which is used to design rates that provide desired price signals to customers. The Department reviews the utility's customer load data, how much and when each customer class uses the services provided by the utility. Load data is used to allocate costs to the various rate classes and design cost based rates to deliver the appropriate price signals. In setting base rates the Department may create new rate classes and combine existing classes based on the goals it seeks to achieve within the constraints of Department precedent (rate continuity, fairness, principles of cost causation, elimination of inappropriate subsidies).

The final component of the base rate case is the actual design of the rates for each class and the individual rate elements (monthly fixed customer charge, demand charge and variable or energy charges). Given the Department's goal to implement a rate scheme that removes disincentives for utilities to fully and aggressively support efforts to implement demand side energy efficiency measures, the Department should carefully determine what rate designs and tariff provisions serve this purpose. Tariff availability

provisions should be written and rate classes designed to assure that customers are correctly assigned to classes that reflect demand and usage characteristics. Customers should not be able to switch classes inappropriately thereby creating subsidies and shifting costs. Load data is critical to the type of rate design initiative that is contemplated by the Department. Without accurate, reliable and up-to-date load data, base rates may not accurately reflect current usage patterns resulting in rates that yield inaccurate and undesired price signals. It is especially important to use accurate information when the base rates will serve as the basis for annual adjustments.<sup>30</sup>

A new concern that the straw proposal poses relates to the need to accurately determine the average revenue or use per customer. The Department must make this determination in a fully adjudicated base rate case to assure that class usage and revenue profiles are accurate because these are the underpinnings for the decoupling adjustments, and they should remain constant until the next base rate case where average revenue and use per customer may be reexamined for future periods.

Rates that are currently in effect for these utilities have been deconstructed through unbundling, restructuring and adjustment clause changes. Rates paid by customer class members may no longer be sending the price signals they were originally designed to or appropriate price signals. Class specific rates may no longer be cost based. Customer consumption patterns and load profiles may have changed significantly. Before introducing any new rate scheme, the Department must set just and reasonable rates for each customer class by carefully analyzing the costs and usage patterns

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<sup>&</sup>lt;sup>30</sup> This is important in the design of any variable rate component, especially time differentiated rates, block rates and demand based charges.

associated with each class. This action alone will likely result in increased rates, even before the issue of decoupling is addressed.

# VIII. ALTERNATIVES TO THE DEPARTMENT'S STRAW PROPOSAL AND ADDITIONAL ENERGY EFFICIENCY PROGRAMS

If the Department's overall goal is to foster greater DSM, other options, including alternative ratemaking formats and other non-ratemaking approaches to increase DSM should be considered in conjunction with or in lieu of decoupling. Simple legislative or regulatory changes could have a much greater energy and environmental impact than the Department's straw proposal.

### A. Rate Design Solutions

If the Department determines that there is a utility disincentive and that disincentive must be removed in order to achieve the State's DSM and renewable generation policy goals, there are rate design changes that can be made that would either eliminate or significantly mitigate any deleterious effects declining sales/revenues per customer may have on utilities' profits. The Department has previously noted that rate design is an alternative approach to reducing earnings instability. *Bay State Gas Company*, D.P.U. 92-111, p. 56 n. 26 (1992).

Most of a distribution utility's costs are fixed, but utilities recover the vast majority of their total costs through volumetric charges. When a utility's sales volumes are lower than the volumes used to set its rates, the utility may not earn the level of profit

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anticipated.<sup>31</sup> Rather than make a wholesale change to the way the Department has set utility rates, the Department could move to designing rates that would collect more of a utility's fixed costs through the rate elements that do not vary with customer consumption levels—monthly customer charges or demand charges.<sup>32</sup> The Department could make gradual changes that would shift cost recovery to these fixed rate components over time thus avoiding immediate adverse rate impacts to lower use customers. This approach would not conflict with Department precedent of setting rates based on the principles of cost causation and would not violate rate continuity concerns.

Shifting cost recovery to the fixed rate elements diminishes or may even eliminate volumetric distribution rate components. It could affect the level of savings a customer would experience when implementing energy efficiency—but distribution costs are not the energy costs that DSM projects should seek to avoid. When energy efficiency providers and customers evaluate the cost savings due to the installation of energy efficiency products, the benefits may be lower but the price signal is more accurate. Avoiding commodity costs mitigates the social and economic risk associated with climate change and minimizes the environmental impacts of energy production. Avoiding fixed distribution costs only increases the frequency of rate cases and new ratemaking mechanisms designed to make utilities whole.

<sup>&</sup>lt;sup>31</sup> Utility rates are set based on a level of customers and sales volumes that the Department deems to be representative of the levels that will be achieved during the period the rates are to be in effect. If a utility is unable to reduce costs and overall sales volumes decrease from those used to set rates, profits may be lower than forecast. The Department allows natural gas companies to weather normalize its sales levels.

<sup>&</sup>lt;sup>32</sup> By shifting cost recovery to fixed rate elements the Department would be removing a significant element of business risk, just like decoupling. In addition, as with the Department's straw proposal, the utilities would retain profits related to growth in the number of customers. Customer growth provides significant profits for utilities—the level may be assessed by reviewing the marginal costs as compared to the revenues generated by new customers regardless of the new customers' level of use. Utilities should retain only the marginal cost associated with new customers and crediting retail sales customers with revenues in excess of marginal costs under methodology designed to stabilize utility profits.

### **B. Peak Pricing Option**

The Department has authority to implement rate design changes that go beyond base distribution rates and produce customer benefits that can be derived from providing options to all customers in a complete and effective package of price signals. For the portion of customers without competitive energy suppliers—basic or default service customers, the Department has been reluctant to require that utilities provide basic service to customers on any basis other than as a pass through of third party supplies procured competitively. This service is load following service aggregated by essentially two classes (large business and small-business and residential) on the electric side.

On the gas side, commodity costs are again directly passed through, albeit on a seasonally differentiated basis.<sup>33</sup> Natural gas default service customers pay a Cost of Gas Adjustment ("CGA") factor that reflects seasonal price differences. Electricity customers' rates are generally fixed for six month periods for small and medium customers and may be fixed for three month periods for large businesses. Currently, electricity customers have no other pricing options available to them under basic service tariffs.

In order to maximize benefits to customers of any enhanced energy efficiency and demand side management efforts, as part of the Department's proposed rate setting process, it should require that each utility should design an *optional* peak pricing pilot program, open to all customers. The program should be a stand alone service where all costs would be recovered from participating customers. This program would allow

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<sup>&</sup>lt;sup>33</sup> Gas costs for some utilities are differentiated by load factor based groups—high load factor and low load factor. The differentiation follows distribution tariff availability provisions. Load factor based CGAs were adopted to avoid cherry picking by competitive suppliers not for reasons related promoting conservation or energy efficiency.

interested customers, generally those with the ability to shift and conserve consumption, to enjoy higher savings than are now available to them and without increasing costs to other customer groups that may not have the ability to generate additional demand side savings.

#### C. Other Alternatives

As cited above, in it most recent report and 2006 Energy Efficiency Scorecard, the American Council for an Energy-Efficient Economy found that Massachusetts ranked lower than other states with regard to building codes, appliance standards, energy efficiency resource standards, tax incentives and state lead-by-example.<sup>34</sup> The policy areas where Massachusetts earned relatively low ratings have little to do with utility-implemented DSM programs or ratemaking policies. Such non-regulatory policy changes could be implemented independently or in conjunction with decoupling. Many of these proposals offer a more simplified method than a decoupling rate mechanism for reaching the goals of increased energy efficiency without some of the potential risks associated with implementation of decoupling.

In addition to the regulatory review of the merits of decoupling, the Commonwealth should pursue other efficiency initiatives including: improved building codes aimed at reducing heat loss and improving overall energy efficiency; phasing out the use of incandescent or "normal," non-fluorescent light bulbs;<sup>35</sup> state tax incentives for the purchase and use of energy efficient products, tools and appliances; and further

<sup>34</sup> See supra, pp. 14-15.

<sup>&</sup>lt;sup>35</sup> A 15-watt fluorescent bulb produces approximately the same amount of light as a 60-watt incandescent bulb. Eliminating incandescent bulbs will save consumers five to ten percent of the state's current energy consumption.

energy efficiency standards for most appliances sold or offered for sale in the state. Also, the current system of utility administered energy efficiency programs could simply be expanded by using other energy-related resources. Additional funding may become available from the RGGI or from bidding the utility DSM programs into the ISO's Forward Capacity Market without increasing utility rates more than they would increase otherwise.

Finally, if the Department finds that utilities have a proven disincentive to increasing energy efficiency and/or that our current energy efficiency programs are not working as they should, the method of DSM program delivery itself could be overhauled by using an entity other than the distribution company to administer energy efficiency programs. The Legislature has determined that the Department "shall ensure that [DSM] are delivered in a cost-effective manner utilizing competitive procurement processes to the fullest extent practicable." G.L. c. 25, § 19. One alternative to our present method of DSM program delivery is to have a third party administrator implement DSM programs. Less utility control or discretion over DSM programs would essentially eliminate disincentives to the expansion of existing programs and the implementation of new programs. Use of a single, statewide administrator and delivery through the use of competitive entities would be more efficient than the current utility run programs. A third party administrator would lower the potential of a utility interfering with costeffective energy efficiency programs by eliminating the utilities' control over the implementation of new and existing DSM programs.

Moving the administration of all energy efficiency programs from utilities to either a state agency or third party administrator would also allow for expanded programs at a

lower cost without any new dollars being spent. A third party administrator would eliminate the necessity for incentive payments being paid to companies, freeing up millions of dollars for new and expanded programs. This approach would result in savings of the eight percent markup on energy efficiency programs provided to utility companies as an incentive to administer the programs. A third party administrator would also gain from economies of scale through a statewide program with a single administrative body as opposed to each utility managing its program independently. Finally, a third party administrator would ensure more uniformity in energy efficiency programs across the state. At least six states have energy efficiency programs delivered by an entity other than the transmission and distribution utility. Often a state agency or state-sponsored private entity manages the state's energy efficiency programs. These states include Maine, Vermont, New York, New Jersey, Wisconsin and Oregon. In Vermont, Efficiency Vermont was created in 2000 by the Vermont Legislature and the Vermont Public Service Board. Vermont electric utilities stopped providing energy services when Efficiency Vermont began providing services.

> Respectfully submitted, MARTHA COAKLEY ATTORNEY GENERAL

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#### APPENDIX A

#### **DEPARTMENT QUESTIONS**

#### **Allowed Revenues per Customer**

1. The Department's proposal that a company's allowed revenues per customer be determined through a subsequent base rate proceeding is intended to ensure that the allowed revenue levels, which serve as the basis for the base revenue adjustment mechanism, are closely aligned with the company's costs. Under what, if any, circumstances should the Department permit a company's allowed revenues per customer to be determined through some manner other than a base rate proceeding?

The Department should always determine a company's allowed revenues per customer through a base rate proceeding. A thorough review of each utility's cost of service is necessary to establish the appropriate "cast-off" rates before implementing a base revenue adjustment mechanism. *See Boston Gas Company*, D.P.U. 96-50, pp. 346-347 (1996) (The Department must determine the appropriate "cast-off" rates before establishing performance-based rates.) The Department's proceeding will not only determine the appropriate costs and revenues that will be used to establish these rates but also the billing determinants that will be critical in establishing the appropriate revenue per customer benchmark that could be in effect for many years. Evidentiary hearings are necessary to ensure, at least initially, that the rates are just and reasonable as required by the provisions of G.L. c. 164, § 94.

2. The Department's proposal uses an approach in which a company's allowed revenues per customer for each rate class does not change between base rate proceedings. An alternate approach would be to adjust the allowed revenues per customer values periodically, based on changes in each rate class' average usage per customer. Please discuss the merits of each approach.

The proposal of using a company's allowed revenues per customer for each rate class without changes between base rate proceedings provides the simplest, least controversial method, after rates have been established. This approach, however, will cause a huge shift in financial and business risk from the utility's shareholders to its customers. The shifted risks include at least the following: weather, price-demand effects, economic cycles, customer initiated/financed energy efficiency, distribution system outages, and customers switching to self-generation. A change of this magnitude would require a significant reduction in the company's cost of common equity.

The suggested alternative approach of adjusting the allowed revenues per customer periodically in between base rate cases could cause the utility to retain some of the risks associated with usage. Again, one could normalize the actual usage per customer for the effects of weather, price-demand effects, economic cycles, customer initiated/financed

energy efficiency, distribution system outages, and customers switching to selfgeneration. The adjustment to the actual usage per customer amount for each one of these factors, however, will further complicate the base rates of each company. Furthermore, the determination of and the assumptions used to make these adjustments will cause a tremendous amount of litigation regarding each factor and, in the end, will be, at best, guesstimates.

#### **Annual Reconciliation Calculation**

3. The Department's proposal that a company's actual versus allowed revenues be reconciled annually is intended to balance three objectives: rate stability, rate continuity, and administrative efficiency. Do annual reconciliations strike an appropriate balance among these three objectives or would alternate reconciliation periods (e.g., quarterly or semi-annually) better do so?

The rates, under the Department's proposal, generally should be adjusted on an annual basis to provide some balance between rate stability, rate continuity, and administrative efficiency. The annual reconciliation alone will create an annual series of fourteen single issue rate cases. Additional quarterly or semi-annual reconciliations will compound the problem creating an enormous administrative burden.

Providing greater energy cost predictability is a valuable element of customer service and is in the public interest. *Boston Edison Company*, D.P.U. 94-1D, p. 16 (1994). The Department should monitor the companies using an annual reconciling mechanism to insure that the total amounts being deferred for recovery from or returned to customers do not become too large relative to the total distribution rate. When those deferrals become too large, rates should be adjusted intra-period to maintain some level of rate continuity, while providing an absolute cap on the increases equal to three percent of distribution rates. When the Department considers continuity in rates, it seeks to avoid any unacceptable discontinuities in terms of the total bill impacts. *Boston Edison Company*, D.P.U. 85-266-A/85-271-A, pp. 193-194 (1986). This requires consideration of the entire bill. *Bay State Gas Company*, 95-104, p. 16 (1995).

4. The Department's proposal to determine a company's actual revenue based on billed revenues is consistent with the base rate treatment applied to distribution-related bad debt costs. An alternate approach would be to determine actual revenues based on payments received. Please discuss the merits of each approach.

The Department's proposal to determine a company's actual revenue based on billed revenues would make a simpler mechanism and continue the incentive for the company to recover bad debt from customers. The alternative approach that determines actual revenue based on payments received would make for a more complicated mechanism. Importantly, however, it would remove any incentive for the company to recover bad debt from customers, thus shifting the risk of bad debt from shareholders to customers.

- 5 The Department's proposal for determining billed revenues is based on actual consumption. An alternate approach would be to determine billed revenues based on consumption normalized for weather and/or other factors.
  - a. Please discuss the merits of determining billed revenues using actual versus weather-normalized consumption.
  - b. Should consumption be normalized for other factors (e.g., economic conditions)? If so, identify those factors and describe how the normalization for such factors could be done.
- a. The Department's proposal to determine billed revenues based on actual consumption would transfer the financial risk associated with all variation in per customer usage from the company's shareholders to its customers, including variability associated with weather, price-demand effects, economic cycles, customer initiated/financed energy efficiency, distribution system outages, and customers switching to self-generation. This change in risk requires the Department to make a commensurate reduction in the Company's cost of capital. Although normalizing the actual sales for weather would leave weather risk with the shareholders, the significant risks associated with the many other factors effecting customer usage would still be transferred to customers, requiring a significant reduction in the company's cost of capital.

The implementation of a revenue adjustment mechanism, with or without normalizing for the effects of weather on consumption, requires an immediate reduction in base rates in all cases to reflect the lower investment risk and lower investment return requirement. These changes should all be made in the context of a base rate proceeding that allows for a complete review of the revenues, costs, and billing determinants of the company. Furthermore, the Department should also immediately reduce all other non-distribution rates that incorporate a carrying charge to reflect the company's reduced cost of capital.

b. In theory, the Department should normalize actual revenue for all factors effecting customer usage except for the changes caused by the energy efficiency programs that are administered by the Company. Normalizing actual consumption, however, for each of these factors will make the proposed revenue adjustment mechanism exponentially more complicated with the normalization of each additional factor, since each of the factors will be, to some extent, dependent on the other factors effecting usage. Furthermore, determining the normalization equations for each of the factors will cause a tremendous amount of litigation amongst the stakeholders. Therefore, although isolating the effects of the utility administered energy efficiency programs on customer usage is the goal, implementing the mechanism would be extremely complicated and most likely very contentious.

The Department, in normalizing the revenue adjustment mechanism for each factor effecting customer usage, would have to adjust the company's cost of capital for each

risk the Department shifts from investors to customers. The risks that the Department's straw proposal shifts to customers include the risks associated with weather, price-demand effects, economic cycles, customer initiated/financed energy efficiency, distribution system outages, and customers switching to self-generation which requires a significant decrease in the company's cost of capital. Each shift by itself, however, causes a decrease in the company's cost of capital that must be accounted for through a concomitant decrease in the cost of capital and the associate base rates. Therefore, the change in risk and return will depend on the extent that the Department "normalizes" the actual revenues per customer for the effects of these other factors.

#### **Annual Base Rate Adjustment**

6. The Department's proposal to recover the difference between a company's target and projected revenues through adjustments to its base energy charges is intended to send appropriate price signals to consumers. An alternate approach would be to adjust both base energy and demand charges (where applicable) to recover this difference. Please discuss the merits of each approach.

The Department's revenue adjustment mechanism should be based on the difference between a company's target or benchmark revenue per customer, as established in a base rate case, and the actual revenue per customer, determined with historical accounting information, not a projected amount per customer. Furthermore, the revenue adjustment mechanism must be a fully reconciling item that provides for corrections of any errors, without any question of retroactivity. Ultimately, any mechanism should adjust to the company's actual revenue, rather than some projected level.

In either case, the Department's proposal to recover the difference between a company's target or benchmark and projected revenues through adjustments to it base energy charges may not provide the correct price signals. This proposed method signals to customers that the more they conserve energy, the more it costs per unit. Conversely, when they use more energy, it will cost them less on a per unit basis. This is not the appropriate price signal that customers should be given, if one wishes to promote energy efficiency and conservation.

The Department's proposal with energy only, or demand and energy charge adjustments, in either case, will not send the appropriate price signals. Nevertheless, the energy only adjustment would be simpler for the company to administer and more easily understood by customers. Furthermore, in the vast majority of cases, the total dollar change in the final bill should be *de minimis*.

#### **Reconciliation Filings**

7. The Department's proposal to require a company to submit quarterly filings identifying actual and allowed revenues is intended to ensure that changes in rates are made in a predictable and gradual manner.

- a. Under what circumstances should the Department allow an adjustment in base charges during a reconciliation period?
- b. Under what circumstances should the Department initiate a review of a company's base revenue adjustment mechanism?
- a. The Department should allow intra-period rate adjustments in those instances when the deferred balances have reached a certain threshold percentage of expected annual distribution revenues. The mechanism would operate similar to the manner in which the Department administers the Cost of Gas Adjustment Clause, providing for intra-period changes to rates when the deferral of under- or over-recoveries has reached a level of three percent of total expected distribution rate recoveries. These intra-period adjustments would provide for better rate continuity. However, when the adjustments for any year are greater than three percent, the Department should open an investigation to review the totality of the company's cost of service and revenues to insure that rates are just and reasonable.
- b. The Department should initiate reviews of a company's base revenue adjustment mechanism whenever it finds reasonable cause to do so. This investigation could be initiated because of some failure of the mechanics of the revenue adjustment mechanism, the financial performance of the company, or the poor performance of the energy efficiency programs. This review could be as a result of the Department's initiative or as the result of a petition by an interested party or group of parties seeking such review. Finally, the Department should open an investigation to review the totality of the company's cost of service and its revenues to insure that the rate is just and reasonable, when the total adjustment for any year is greater than three percent of the distribution revenues in that year.

# 8. What standards should the Department use to measure the performance of a company's base revenue adjustment mechanism over time?

The Department should review the performance of the base revenue adjustment mechanism based on several criteria. These criteria should include the administrative aspects of the mechanism itself, the specific company's performance regarding its administration of the demand-side management programs, the effectiveness of the energy efficiency programs themselves, and the changes in financial profile of the company as it relates to the intended effects of the adjustment mechanism. Each of these is discussed below.

The Department should review the administrative aspects of the mechanism to insure that the formulas, reconciliations, intra-period adjustments, inter-rate effects, etc., are all working as intended in calculating the revenue adjustment. The Department should then make changes to the mechanism as quickly as possible to correct the problems that are found.

The Department should also review the individual company's performance to determine whether it is effectively and economically promoting DSM programs. To the extent that the Department finds that the company is failing to properly administer the DSM programs, the Department should deny any proposed base rate increases as a result of the revenue adjustment mechanism or otherwise.

The Department should also review the effectiveness of the energy efficiency programs themselves. If the energy efficiency programs are not providing the intended results in terms of the magnitude of usage reduction, then a review of those programs, along with termination of the revenue adjustment mechanism would be appropriate.

Finally, the Department should review the performance of the company's base revenue adjustment mechanism to determine the effect on its financial performance and the interaction with the company administered DSM programs. If the company is consistently earning above its allowed return on common equity, as established in its last base rate case, the Department should consider adjusting the mechanism or denying future adjustment. Furthermore, to the extent that the revenue adjustment mechanism is providing unnecessary rate increases, when the company administered programs are failing to cause decreases in customer usage, service quality has degraded, or reductions in maintenance and/or capital investment potentially jeopardize operations, then appropriate adjustments to or total abandonment of the mechanism should be ordered by the Department.

#### **Change in Risk**

9. How will the implementation of a base revenue adjustment mechanism affect a company's risk and how should such considerations be reflected in a company's capital structure and ROE?

The Department's proposed revenue adjustment will create a material economic benefit for the company's shareholders at the expense of its customers. The implementation of a base revenue adjustment mechanism will cause a significant decrease in a company's investment risk profile as the risks associated with revenue variability will shift from the company's investors to its customers. The effect of this decrease in the company's investment risk profile will be to decrease the required return on all of the company's financings. All debt holders and equity holders will need less of a return as a result of the implementation of the revenue adjustment mechanism.

The precise effect on the cost of capital will depend on the specific parameters of the revenue adjustment mechanism that the Department implements, however, it is clear that a revenue decoupling mechanism at least will reduce the variance in the company's future revenue streams. The return should decrease for each risk the Department shifts from investors to customers. The risks that the Department's straw proposal shifts to customers include the risks associated with weather, price-demand effects, economic cycles, customer initiated/financed energy efficiency, distribution system outages, and customers switching to self-generation which requires a significant decrease in the

company's cost of capital. Each shift by itself, however, causes a decrease in the company's cost of capital that must be accounted for through a concomitant decrease in the cost of capital and the associate base rates. Therefore, the change in risk and return will depend on the extent that the Department "normalizes" the actual revenues per customer for the effects of these other factors. For instance, the Department suggests that it might normalize actual revenues for weather, if it were to apply its revenue adjustment mechanism. The effect of weather normalization on the revenues would be to keep the risk of variability of sales caused by weather changes with the company, meaning that a smaller downward adjustment in the cost of capital would be necessary. Similarly, if the Department normalized for each of the other risk factors that effect sales, including pricedemand effects, economic cycles, customer initiated/financed energy efficiency, distribution system outages, and customers switching to self-generation, the impact on the cost of capital would become much smaller. Finally, it should be recognized that investors holding the utility's debt will necessarily see a windfall with each risk factor that the Department shifts to customers as their contractual debt service payments will not change, while the associated risk decreases.

The implementation of a revenue adjustment mechanism requires an immediate reduction in base rates in all cases to reflect the lower investment risk and lower investment return requirement. These changes should all be made in the context of a base rate proceeding that allows for a complete review of the revenues, costs, and billing determinants of the company. Furthermore, the Department should also immediately reduce all other non-distribution rates that incorporate a carrying charge to reflect the company's reduced cost of capital.

Finally, the implementation of the Department's new revenue adjustment decoupling mechanism would also require the elimination of all other decoupling mechanisms. Specifically, the Department would have to remove all lost base revenue recoveries as well as all profit markups on program costs that have been used historically to incent the companies to provide energy efficiency programs. The new adjustment would make these recoveries redundant, unnecessary and unreasonable.

#### **Shared Earnings Provision**

10. The Department's proposal to include a shared earnings provision in the base revenue adjustment mechanism is intended to strike an appropriate balance between the risks borne by customers and shareholders associated with company earnings. Please comment on the merits of such a provision. Also, comment on the design of the proposed earnings sharing provision.

The Department's proposal to include a shared earnings provision with the revenue adjustment mechanism is an option that could be included; if the Department simultaneously eliminates the company's price cap rate increases, if any. The inclusion of the shared earnings provision would provide the company with some protection from insufficient earnings levels, thus reducing the need for base rate increase filings before the Department on a going forward basis.

The design of a shared earnings provision to be implemented with the Department's revenue adjustment mechanism should be similar to that currently employed by the Department in its price cap earnings sharing mechanism, providing sharing of earnings surpluses and earnings deficiencies outside of a symmetrical *deadband* around the company's allowed return on common equity.<sup>36</sup>

#### **Performance Based Regulation**

11. Please comment on the merits of implementing a base rate adjustment mechanism with and without the individual elements of a PBR plan (e.g., fixed term, inflation, productivity, performance standards, exogenous factors).

The Performance Based Rate Plans ("PBR") are inapposite to the proposed base rate adjustment mechanism.<sup>37</sup> While a PBR attempts to separate rates from costs during the plan period, <sup>38</sup> a base rate adjustment mechanism is designed to ensure "that revenues would be more closely aligned with costs over time." June 22 Order, p. 12. The proposed base rate adjustment is designed to insure recovery of a regulated company's historic or embedded costs through adjustments to revenues. A PBR in theory allows a company to keep higher earnings that arise from increased productivity gains.<sup>39</sup> In establishing the PBR mechanism for distribution companies, the Department found that "well-designed incentive mechanisms should provide utilities with greater incentives to reduce costs than currently exist under traditional cost of service regulation and should result in benefits to customers, whether in the form of lower prices or increased service, which are greater than would be present under current regulation. Boston Gas Company, D.P.U. 96-50, p. 242 (1996) citing *Incentive Regulation*, pp. 54-55 (1995). [emphasis added]. As a result, utilities under the Department's price cap mechanism have the incentive to increase sales. This is in direct conflict with decoupling of the companies' revenues and sales. Therefore, the Department, if it implements a revenue adjustment mechanism for decoupling similar to its straw man, should eliminate the current price cap revenue adjustment mechanism.

Combining the two may lead to a decoupling mechanism reconciling revenues to an ever increasing rate under a PBR. These theories of regulation are not compatible with each other and hybridizing the different approaches by borrowing concepts, like productivity adjustments and grafting it onto a decoupling mechanism serves only to further enhance

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<sup>&</sup>lt;sup>36</sup> If the earned return is within the deadband around the allowed rate of return on equity, it is difficult to understand why further annual adjustments would be needed.

<sup>&</sup>lt;sup>37</sup> Under cost of service or rate of return regulation, rates are cost based as they are designed to produce revenue equal to the revenue requirement needed by the utility to cover its costs and fair return on investment. *Incentive Regulation*, D.T.E. 94-158, p. 3 (1995). PBRs are intended to separate rates from costs "by tying allowed revenue bonuses or penalties (usually stated in terms of rate of return basis points) to performance in the target areas." D.T.E. 94-158, p. 17.

<sup>&</sup>lt;sup>38</sup> *Incentive Regulation*, D.T.E. 94-158, pp. 19, 26, 51 (1994).

<sup>&</sup>lt;sup>39</sup> Under a PBR rate a utility knows it will be rewarded for efficiency and penalized for inefficient operations and will take a more aggressive approach to control costs. *Incentive Regulation*, D.T.E. 94-158, p. 46 quoting Notice of Inquiry at 4, n. 2.

utility profits at the expense of reasonable rates and will not further the goal of achieving more efficient deployment of DSM. Both PBR and decoupling mechanisms involve immensely complicated calculations and implementing both would significantly add to administrative and regulatory costs. If a base rate adjustment is allowed, then the Company should also not have a PBR Plan.

As part of the Restructuring Act, the Legislature enacted General Laws, c. 164, § 1E which authorized the Department "to promulgate rules and regulations to establish and require performance based rates for each distribution, transmission, and gas company organized and doing business in the commonwealth pursuant to the provisions of this chapter." By the enactment of this section, the Legislature has indicated its intent that the Department adopt PBR ratemaking. "The Department's job is to effect legislative intent." *Re Establishing Complaint and Enforcement Procedures*, D.T.E 98-36A, p. 2 (2000). If, as it appears, PBR and decoupling mechanisms are incompatible or redundant, the Department must determine whether its can abandon PBR ratemaking under the existing statutory scheme in order to implement decoupling.<sup>40</sup>

Furthermore, Section 1E also directs the Department to establish minimum standards of service quality ("SQ") for companies operating under PBR plans. *Bay State Gas Company*, D.T.E. 05-27, p. 410 (2005). The Department has applied the service quality guidelines established in *Service Quality Standards*, D.T.E. 99-84 (2001) to those distribution companies operating under either PBR plans or merger/acquisition-related rate plans. *See Boston Edison Company*, D.T.E. 01-71A, pp. 8-9, 12-18; *Massachusetts Electric Company*, D.T.E. 01-71B, pp. 6-26 (2002); D.T.E. 99-84, Letter Order, pp. 5-6 (May 28, 2002); D.T.E. 99-84, Letter Order at 3-6 (April 17, 2002). The Department has found that because PBR and similar rate plans introduce a financial incentive for the regulated company to reduce costs, a well-designed plan must include some form of protection against a reduction in service quality for the monopoly customers. *Boston Gas Company*, D.P.U. 96-50 (Phase I), p. 304 (1996); *Boston Gas Company*, D.P.U. 96-50-C, pp. 59-79 (1997); *Boston Gas Company*, *d/b/a KeySpan*, D.T.E. 03-40, p. 504 (2003).

If the Department adopts a base rate adjustment mechanism, it must also maintain or improve existing utility service quality. The Department's general supervisory powers provide it with the authority to impose service quality measures on companies without a PBR mechanism. *See* G.L. c. 164, § 76. The Department should clearly indicate that the service quality standards adopted in D.T.E 99-84 are to apply to all gas and electric companies operating under a base rate adjustment mechanism.

#### **Implementation Schedule**

12. Please comment on how the Department should schedule the implementation of a base revenue adjustment mechanism for each gas and electric company in light of the need to move expeditiously, the resources required to implement such

<sup>&</sup>lt;sup>40</sup> In the Department's view, the language of G.L. c. 164, §1E(a) "does not obligate the Department to implement PBR, it simply authorizes it to do so." *Eastern Enterprises*, D.T.E. 98-128, p. (1999).

# changes, and the specific circumstances of each company. How should the Department determine the order of individual base rate proceedings?

Under no circumstances should speed trump the need to implement decoupling in a prudent and responsible manner. A change in rate making principles of this magnitude for each company implemented through a full base rate case will take significant time and resources. The administrative burden that would be placed on all parties, including the Department, of having the companies rush in to implement any base revenue adjustment mechanism would lockup the regulatory process with as many as 14 full blown rate cases, allowing little, if any, of the other important regulatory/rate issues to be fully considered for years. Any implementation of the mechanism would have to be rolled out over several years to provide for the serious contemplation of the rates and rate mechanisms that the consumers and the companies will require.

Moreover, many of the electric and natural gas companies are currently under long-term rate plans, some as the result of fully litigated rate cases and others as the result of rate settlements. The Department should not, and in the case of settlements cannot, upset those rate plans as they were carefully formulated and balanced to provide the right incentives for the companies to perform in the long-run. Ordering those companies under rate plans to file before those plans terminate could well harm customers, or the companies, providing the harmed party with possible legal grounds for restitution, negating the effects of the revenue adjustment mechanism, making it moot.

The Department has experience in implementing complex regulatory changes. The Department should consider the manner in which it rolled out the PBR plans with the Price Cap rate mechanism. Rather than "lining companies up" to impose the Price Cap mechanisms on them as quickly as possible, the Department simply ordered the plans be implemented with each company's next base rate filing. This next base-rate-case methodology has provided for a less controversial, administratively possible solution to the problem. It will also allow the Department to provide for any necessary tailoring of the rates, incentives and energy efficiency program improvements to the particular company. The Department, therefore, should not order the companies to file as quickly as possible to implement any proposed rate mechanism, and should instead require each to file for the necessary changes with their next base rate case filing.

Finally, the Department could follow the lead of other states such as Vermont and Idaho and implement decoupling for a company or companies through a rate proceeding or settlement agreement for a limited number of years. In Idaho, decoupling for electricity was approved through a settlement with Idaho Power, which provides for a three year program and provides for the evaluation of the rate mechanism. *Investigation of Financial Disincentives to Investment In Energy Efficiency*, Case No. IPC-E-04-15 Idaho Public Utilities Commission, (2007). Likewise in Vermont, a decoupling plan was approved for Green Mountain Power for three years. *Green Mountain Power Corporation*, Docket No. 7176 Vermont Public Service Board (2006). The problems with the implementation of a base rate mechanism that provides for a sea change in the rate design, incentives, and financial aspects of the ratemaking process should not be

done in a wholesale, rushed manner. Prudence dictates that an incremental, experimental approach to such dramatic changes in the ratemaking process may be the best path to follow.

#### **Other Questions**

13. How should the implementation of a base revenue adjustment mechanism affect the performance-based shareholder incentives that gas and electric companies currently are eligible to receive for promoting energy efficiency?

The Department should eliminate the electric and gas companies' other performance based incentives to promote energy efficiency, if it implements a base revenue adjustment mechanism and maintains the administration of the energy efficiency programs with the companies. *See* response to Question 11. The imposition of the base revenue adjustment mechanism is intended to eliminate the companies' incentive to sell more units of energy. Furthermore, maintaining the administration of the energy efficiency programs with the utility makes those programs utility functions. Therefore, there is no longer any need to provide incentives for what would now become a basic utility function.

The Department, however, must still ensure that the companies act prudently and economically in carrying out the administration of the energy efficiency programs. Like answering the phones and repairing distribution lines, the companies' performance regarding energy efficiency programs should become part of the service quality index. A standard index should be adopted for energy efficiency and incorporated into the overall service quality index for each company with penalties for sub par performance.

## APPENDIX B

Table 5.6.A. Average Retail Price of Electricity to Ultimate Customers by End-Use Sector, by State, May 2007 and 2006 (Cents per Kilowatthour)

(Cents per Knowatthour)											
Census Division and State											
	Reside	Residential		Commercial <sup>1</sup>		Industrial <sup>1</sup>		Transportation[1]		All Sectors	
	May-07	<b>May-06</b>	May-07	May-06	May-07	May-06	May-07	May-06	May-07	May-06	
New England	16.32	16.58	13.84	14.2	11.99	9.89	7.93	6.85	14.26	14.11	
Connecticut	19.56	16.99	15.03	13.55	12.53	11.1	14.34	11.19	16.1	14.34	
Maine	15.19	15.88	12.17	11.89	11.63	7.53			13.45	11.99	
Massachusetts	15.53	17.08	13.81	14.95	12.25	9.74	5.36	4.93	13.92	14.58	
New Hampshire	15.19	16.1	13.35	14.95	11.86	11.15			13.72	14.55	
Rhode Island	13.48	15.45	12.33	14.15	11.92	11.99			12.67	14.25	
Vermont	14.42	13.77	12.63	11.94	8.6	8.28			12.06	11.46	
Middle Atlantic	14.19	13.08	12.94	11.31	7.92	7.22	11.32	10.69	12.24	10.88	
New Jersey	13.34	11.47	12.19	10.77	10.77	8.52	11.23	7.97	12.36	10.65	
New York	17.46	16.31	15.43	13.02	8.71	8.71	12.12	11.8	15.19	13.33	
Pennsylvania	11.37	10.83	9.53	8.98	7.05	6.34	7.76	7.6	9.23	8.57	
East North Central	10.04	9.74	8.57	8.33	5.81	5.37	6	6.47	7.97	7.56	
Illinois	10.4	9.01	8.43	7.91	6.57	4.34	5.44	5.95	8.56	7.01	
Indiana	8.74	9.19	7.28	7.58	4.94	5.1	10.01	9.53	6.52	6.7	
Michigan	10.18	10.06	9.12	8.93	6.08	6.74			8.37	8.56	
Ohio	9.97	10.02	8.89	8.54	5.77	5.39	10.56	10.48	7.94	7.64	
Wisconsin	11.12	10.86	8.69	8.52	6.22	5.9			8.38	8.18	
West North Central	8.54	8.49	6.75	6.76	4.97	4.82	6.74	5.98	6.74	6.64	
Iowa	9.96	9.86	7.07	7.18	4.58	4.55			6.63	6.6	
Kansas	8.55	8.22	7.09	7.05	5.27	5.42			6.98	6.9	
Minnesota	9.24	8.74	7.03	6.96	5.56	5.12	7.92	7.03	7.13	6.82	
Missouri	7.94	8.24	6.51	6.64	4.77	4.71	5.11	4.64	6.67	6.72	
Nebraska	7.54	7.64	6.27	6.13	4.55	4.31			6.06	5.87	
North Dakota	7.79	7.53	6.34	6.12	4.44	4.23			6.14	5.93	
South Dakota	8.41	8.43	6.38	6.5	4.88	4.82			6.79	6.82	
South Atlantic	9.91	9.94	8.46	8.21	5.3	5.35	8.95	7.64	8.34	8.2	
Delaware	13.47	11.84	11.15	11.74	8.02	5.55			10.98	9.87	
District of Columbia	9.57	9.35	11.71	9.59	9.59	11.41	10.6	9.74	11.36	9.58	
Florida	11.09	11.32	9.58	9.87	7.56	7.58	9.67	10.37	10.13	10.37	
Georgia	9.02	9.02	7.82	7.83	4.94	5.07	6.1	5.82	7.44	7.42	
Maryland	10.49	9.21	11.12	8.87	8.65	9.27	9.36	6.56	10.62	9.05	

### **APPENDIX B**

North Carolina	9.38	9.3	7.24	7	5.18	5.09			7.5	7.28
South Carolina	9.27	9.21	7.49	7.37	4.6	4.53			6.85	6.68
Virginia	8.88	9	6.28	6.24	4.83	4.62	6.89	7.06	6.93	6.84
West Virginia	6.72	6.76	5.72	5.62	3.72	3.65			5.04	4.97
East South Central	8.5	8.49	7.99	7.93	5.05	4.72			6.91	6.71
Alabama	9.22	8.72	8.56	7.88	5.27	4.84			7.36	6.82
Kentucky	7.54	7.59	6.6	6.45	4.34	3.74			5.66	5.25
Mississippi	9.7	9.71	8.96	9.49	5.81	6			8.04	8.32
Tennessee	8.01	8.22	8.07	8.27	5.42	5.26			7.13	7.13
West South Central	11.46	11.34	9.29	8.84	7.11	6.95	8.61	8.61	9.33	9.15
Arkansas	8.41	8.37	6.42	6.53	4.75	5.06			6.36	6.5
Louisiana	9.97	8.72	9.54	8.31	7.2	6.37			8.8	7.74
Oklahoma	8.58	8.05	6.96	6.74	5.16	5.37			6.97	6.82
Texas	12.63	12.71	9.89	9.49	7.85	7.72	8.39	8.43	10.22	10.15
Mountain	9.53	9.43	7.85	7.59	5.51	5.43	7.56	6.74	7.67	7.51
Arizona	10.18	10.16	8.34	8.21	6.28	6.07			8.77	8.66
Colorado	9.55	9.12	7.77	6.83	5.97	6.42	6.94	4.01	7.84	7.42
Idaho	6.08	6.47	4.88	5.5	3.67	3.72			4.64	4.93
Montana	8.87	8.25	8.45	7.36	5.03	4.24			7.43	6.44
Nevada	11.26	11.29	9.78	10.05	7.45	7.27	9.81	9.32	9.33	9.28
New Mexico	9.18	9.11	7.51	7.48	5.56	5.18			7.3	7.16
Utah	8.16	7.74	6.88	6.64	4.45	4.3	7.69	8.14	6.42	6.16
Wyoming	8	8.02	6.36	6.37	4.22	3.81			5.33	5.15
Pacific Contiguous	11.52	11.43	10.65	11.03	7.7	7.02	6.68	5.15	10.29	10.23
California	14.03	14.14	12.1	12.64	9.52	9	6.68	5.12	12.16	12.35
Oregon	7.85	7.42	7.05	7.03	4.9	4.36	6.66	6.79	6.78	6.39
Washington	7.07	6.68	6.4	6.32	4.6	4.06	5.63	5.5	6.22	5.84
Pacific Noncontiguous	20.19	20.33	17	17.12	15.78	16.95			17.56	18.05
Alaska	14.94	15.38	11.71	12.2	11.61	12.66			12.69	13.32
Hawaii	23.18	23.26	20.84	20.86	17.2	18.16			20.18	20.57
U.S. Total	10.76	10.6	9.48	9.15	6.25	5.91	9.7	8.87	8.98	8.66

<sup>[1]</sup> See Technical notes for additional information on the Commercial, Industrial and Transportation sectors.

Notes: • See Glossary for definitions. • Values for 2005 are final. Values for 2006 and 2007 are preliminary estimates based on a cutoff model sample. See Tec Source: Energy Information Administration, Form EIA-826, "Monthly Electric Sales and Revenue Report with State Distributions Report."